part 6

19950002

Hulsebosch

WITNESS DIRECT TESTIMONY SUMMARY

Witness: Thomas G. Hulsebosch

Title: Senior Managing Director with West Monroe Partners, LLC

Summary:

Thomas G. Hulsebosch with West Monroe Partners, LLC ("West Monroe") testifies on behalf of the Company regarding the cost-benefits analysis ("CBA") for the Grid Transformation Plan.

Mr. Hulsebosch first describes the general process and structure of the CBA and summarizes the results of the CBA. He testifies that the benefits of the GT Plan exceed the costs and demonstrate a positive benefit/cost ratio. The CBA thus represents a positive business case from a financial perspective, providing over $3 billion of customer benefits, which represents net benefit to customers of approximately $322.5 million all on a net present value basis.

Next, he outlines the methodology used by West Monroe for valuation of the projected costs and benefits for GT Plan. For costs, West Monroe coordinated with the Company to capture and input capital and O&M costs associated with delivering the GT Plan, including internal and external labor, equipment, software, hardware, and services. West Monroe benchmarked the cost inputs based on industry experience and perspective from similar efforts. For benefits, the nature and value of the customer benefits from the GT Plan have been provided by the Company witnesses who support the individual GT Plan components. Customer benefits are categorized as (1) Total Avoided / Deferred Capital, (2) Total O&M Savings, (3) Total Energy / Demand Benefit, (4) Total Improved Reliability Benefit, and (5) Total Reduction of Bad Debt and Energy Diversion. Additional benefits for GHG reduction, EV ownership savings, and economic impact are separately included in the CBA as "additional benefits."

Finally, Mr. Hulsebosch provides relevant industry perspective and context regarding the GT Plan. He addresses obsolescence concerns of Grid Transformation-related technologies and investments generally, and specifically regarding AMI technology. He notes that the status of AMI Deployment across the United States and the Company's past experience with solid-state meters that have communications devices also provides evidence and support that this technology is not at risk of near-term obsolescence. He provides a white paper with additional details in this area.

DIRECT TESTIMONY
OF
THOMAS G. HULSEBOSCH
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUR-2019-00154

Q. Please state your name, position of employment and business address

A. My name is Tom Hulsebosch, and I am employed by West Monroe Partners, LLC ("West Monroe") as a Senior Managing Director for the Energy and Utilities practice. My business address is 5910 North Central Expressway, Suite 950, Dallas, Texas 95206.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company") with respect to its plan to transform its electric distribution grid (the "Grid Transformation Plan," the "GT Plan," or the "Plan").

Q. Please describe your area of responsibility as it relates to this proceeding.

A. I am a member of the West Monroe Executive team and a member of the board of directors. I help utilities to develop their strategies and projects for grid modernization to optimize costs and benefits based on their unique operating conditions. My team and I work with utilities across the United States and Europe on grid modernization cost benefit analyses, and I have personally worked on more than 20 utility modernization analyses over the past ten years. These efforts have resulted in the refined approach used to quantify the benefits to society, customers, and operations for the Company's Grid Transformation Plan. Additionally, my team and I have supported the implementation and execution of grid modernization programs similar to the GT Plan, to realize the anticipated benefits. This end-to-end experience has informed our approach to cost-benefit analysis and enabled our team to continuously improve accuracy. A statement of my background and qualifications is attached in Appendix A.

Q. What is the purpose of your testimony in this proceeding?

A. West Monroe has worked with the Company to complete a comprehensive cost-benefits analysis ("CBA") for the Grid Transformation Plan. The purpose of my testimony is to describe the general process and structure of the CBA, as well as the cost and benefit inputs and other information provide to West Monroe by the Company, and to support and explain certain customer and societal benefits that I calculated that are associated with the GT Plan. I will also summarize the results of the CBA and provide relevant industry perspective and context regarding the GT Plan.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. Company Exhibit No. __, TGH, consisting of Schedules 1 through 5, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. The table below provides a description of these schedules:

Schedule	Description
1	GT Plan Costs
2	Quantitative Customer Benefits of the Grid Transformation Plan
3	Additional Benefits of the Grid Transformation Plan
4	GT Plan Deployment Timeline Summary
5	AMI Obsolescence White Paper

I also sponsor certain sections of Grid Transformation Plan, the executive summary of Dominion Energy Virginia's plans for grid transformation (the "Plan Document"), as indicated in Appendix A to the Plan Document.

Q. How is your testimony organized?

A. My testimony is organized as follows:

I. CBA Results and Process Summary

II. Quantified Customer Benefits

III. Additional GT Plan Benefits

IV. Obsolescence Considerations

I. CBA RESULTS AND PROCESS SUMMARY

Q. Before you discuss the process for developing the CBA, what are the results of the CBA for the planned GT Plan investments?

A. Figure 1 below illustrates the projected benefits, costs, net present value ("NPV"), and benefit/cost ratio of the GT Plan. Additional benefits related to greenhouse gas ("GHG") emission reductions, electric vehicle ("EV") ownership savings, and overall economic investment impacts are also displayed in this figure as "Additional."

Figure 1

Cost/Benefit Summary (Revenue Requirement Basis)

(in Millions)

BENEFITS & COSTS	PV[1]
BENEFITS *(Asset Life)*:	
Customer	**$3,026.1**
Avoided/Deferred Capital	$375.6
O&M Savings	$265.9
Energy & Demand Savings	$237.5
Improved Reliability	$2,028.1
Reduction of Bad Debt & Energy Diversion	$118.9
COSTS *(Revenue Requirement)* :	**$2,703.6**
Total Net Benefit (Cost):	**$322.5**
Total Benefit/Cost Ratio:	**1.1**

[1]Present Value (NPV) calculated using Weighted Average Cost of Capital (WACC) of 7.62%

	PV[1]
Additional Benefits	**$85.3**
Reduced GHG	$4.1
EV Ownership Savings[2]	$81.2
Economic Impact[3]	$2,829.0
Total + Additional Net Benefit (Cost):	**$407.8**
Total + Additional Benefit/Cost Ratio:	**1.2**

[2]Adjusted to apply 7.2% benefits correlation factor to reduction

[3] Economic Benefits are neither included in the Total + Additional Net Benefit nor in the Total + Additional Benefit/Cost Ratio

Jobs Creation[4]	
Indirect Jobs	17,228
Direct Jobs	4,540

[4]Jobs creation is calculated using a multiplier applied to Millions of $ in Capital Spend (PV)

As can be seen in Figure 1, the benefits of the GT Plan exceed the costs and demonstrate a positive benefit/cost ratio. The CBA thus represents a positive business case from a financial perspective, providing over $3 billion of customer benefits, which represents net benefit to customers of approximately $322.5 million all on a net present value basis. The additional benefits are presented because they are quantifiable, legitimate and reflect benefits to society and individual participants through reduced GHG emissions, savings to EV owners and general economic benefits from the investments made in the GT Plan. The additional benefits have been aggregated and shown separately because they can be considered incremental to the "total" benefits and because they are not tied to benefits that directly impact customers through reduced costs.

Q. What methodology did West Monroe employ in completing the CBA?

A. West Monroe leveraged an established methodology for valuation of the projected costs and benefits for large grid transformation projects. For costs, West Monroe coordinated with the Company to capture and input capital and operations and maintenance ("O&M") costs associated with delivering the GT Plan, including internal and external labor, equipment, software, hardware, and services. For each cost component, the Company provided cost data inputs, unit costs, assumptions, and other information. In the pre-filed direct testimony of the Company witnesses who support individual GT Plan components, they provide the process they underwent to develop the costs whether that be through existing contracts that underwent competitive procurement or new requests for proposals that have led to or will lead to new competitively bid contracts. The individual Company witnesses, therefore, support the reasonableness of the costs of the individual components of the GT Plan. West Monroe, however, benchmarked the cost inputs based on industry experience and perspective from similar efforts. The benchmarking process helped balance scope and investment to match anticipated benefits based on the experience of other utilities. The cost information served as one input to the CBA, which also considers projected annual costs and ongoing operational impacts, and applies inflation and other escalation factors, as appropriate.

As for the benefits calculations provided by the Company, the nature and value of the customer benefits from the GT Plan have been provided by the Company witnesses who support the individual GT Plan components. My Schedule 2 provides a summary of the categories of benefits included in the CBA as well as the sponsoring witness for that benefit calculation. At a summary-level, the customer benefits are categorized as (1) Total Avoided / Deferred Capital, (2) Total O&M Savings, (3) Total Energy / Demand Benefit, (4) Total Improved Reliability Benefit, and (5) Total Reduction of Bad Debt and Energy Diversion.

Again, additional benefits for GHG reduction, EV ownership savings, and economic impact are separately included as "additional" benefits, and I explain how those additional benefits were calculated in more detail later in my testimony. My Schedule 3 provides the calculation for these categories.

Q. Over what period of time are the benefits projected to be delivered to customers?

A. Benefit realization for customers will begin as soon as the GT Plan deployments start and will continue to be delivered in the years and decades that follow. The CBA accounts for deployment dates and the expected useable life of the individual asset being deployed. In other words, once an asset is deployed, the benefit stream tied to it is projected to be realized only from that starting point and during the expected life. My Schedule 4 provides a Deployment Timeline Summary for the GT components.

Q. Please further describe the role that West Monroe played in the calculation of these benefits within the CBA?

A. For each scope area, West Monroe facilitated internal working group workshops with the

Company to identify the specific inputs and data points that would be needed to project the calculation of benefits. In some cases, the benefit values were provided directly to West Monroe and input into the analysis without modification. In other cases, information was provided and additional work was undertaken using established tools, relevant industry knowledge and experience, benchmarking, and other analysis to complete the projection of benefit and incorporate it into the CBA. It should be noted that the overall benefit projections assume that all elements of the GT Plan will be approved.

Q. Has this methodology used for the CBA been leveraged for similar utility investments in other jurisdictions?

A. Yes. The West Monroe CBA has been leveraged by many utilities over the last 10+ years. This includes as a key component of Department of Energy ("DOE") Grant Applications that were selected for award, utility modernization approvals for municipalities across the U.S., formal grid modernization hearings in Massachusetts, Ohio, and California, and multiple internal prudency and benefit cost reviews by utilities across the country.

Q. The costs in Figure 1 are presented on a revenue requirement basis. Please explain.

A. To develop a more comprehensive view of the planned investments, GT Plan costs were provided to Company Witness Gregory J. Morgan in order to calculate costs of a revenue requirement basis. Company Witness Morgan provided the revenue requirement calculations for the GT Plan investments that became inputs into the CBA. Please note, there are differences between the CBA revenue requirement and the revenue requirement presented by Company Witness Morgan, as discussed in his testimony.

Q. Please provide a summary of the investments that are included in the CBA.

A. Detailed cost information for the GT Plan as pertinent to the CBA is provided in my Schedule 1.

West Monroe received detailed cost information by component and sub-component. Please note the CBA includes certain costs and benefits associated with Programs for which the Company is not seeking approval in this proceeding but have benefits that are enabled by GT Plan investments. These include time-varying rates, peak time rebate, prepay, and the Single-Family Residential charging program (Managed Charging) component of the Electric Vehicle program. Accordingly, my Schedules 1-3 include the comprehensive view of all associated costs and benefits; Company Witness Edward H. Baine provides a cost schedule (his Schedule 1) that is specific to what the Company is seeking approval of in this proceeding.

II. QUANTIFIED CUSTOMER BENEFITS

(1) Total Avoided / Deferred Capital

Q. Please explain how the benefits associated with total avoided / deferred capital as presented in the CBA were derived.

A. West Monroe worked with the Company to identify the previously planned investments that would be avoided or deferred as a result of investments within the GT Plan scope. This analysis was based on Company operating history and previously existing plans if the GT Plan were not to move forward. The Company provided details for a wide range of investment types that would be avoided or deferred, including equipment, IT mainframe costs, distribution infrastructure, and others. As noted in Figure 1, the total benefits associated with avoided / deferred capital are approximately $376 million (NPV) over the asset life of the proposed investments.

(2) Total O&M Savings

Q. Please explain how the benefits associated with total O&M savings as presented in the CBA were derived.

A. West Monroe worked with the Company to identify areas of O&M spend that would be eliminated as a result of investments within the GT Plan scope. This analysis was based on Company operating history and existing budgets if the GT Plan were not to move forward. The Company provided these O&M savings details for areas such as AMR meter reading and meter serving costs, AMR and meter servicing vehicle costs, and other avoided truck rolls and operational improvements. As noted in Figure 1, the total benefits associated with O&M savings are approximately $266 million (NPV) over the asset life of the proposed investments.

(3) Total Energy / Demand Benefit

Q. Please explain how the benefits associated with total energy / demand benefit as presented in the CBA were derived.

A. Several of the GT Plan investments will result in the reduction of energy and demand across the Dominion Energy Virginia distribution system, including managed charging of transportation electrification, advanced rates, such as time-varying rates and peak time rebates ("PTR"), prepay, and voltage optimization. For the transportation electrification component of this benefit, West Monroe worked closely with the Company to determine the impact of the scope areas defined under GT Plan, projected behavior and adoption levels of customers in Virginia based on research and data provided by a third-party consultant to the Company, and the cost of energy to determine the system impact of leveraging managed electric vehicle charging versus the current unmanaged approach to electric vehicle charging, including the impact on peak demand system capacity savings.

The estimated population of EVs in the Company's service territory feeds the savings achieved through forecasting the impact of intelligent / managed EV charging for energy and demand relative to unmanaged EV charging. West Monroe collaborated with the Company to perform analysis comparing the system and energy impacts of EV proliferation with and without the Company taking action to improve efficiency and costs with intelligent and managed charging. The differences in those two scenarios (managed vs. unmanaged) is the benefit delivered via intelligent / managed charging programs by the Company. Managed EV charging is modeled to begin in 2020. The quantified energy and demand savings are then multiplied by electricity and capacity price forecasts, respectively.

For the time-varying rates component of this benefit, the demand savings projections were calculated based on a gradual escalation, linked to the full implementation of AMI for time-varying rate and program penetration and participation levels discussed by Company Witness Morgan modeled to begin in 2020 for the experimental portion, and 2025 for the expanded offering. The costs for energy and demand are then multiplied by the quantified energy and demand reductions from the time-varying rates to calculate demand savings.

Similarly, there are energy and demand savings associated with the proposed residential PTR program based on program penetration and anticipated customer behavior. For this opt-in program, the Company would be offering a rebate to customers based on their reduced usage during PTR events that are called during periods of peak energy usage. The demand and energy reductions associated with this program are anticipated to begin in 2026 following deployment of AMI and assume an initial adoption rate of 2%, growing to a peak of 11% by year 2034. The assumed participation level in the program is 50%, and the CBA assumes 10 events to be called per year (5 in the winter and 5 in the summer).

As noted in the testimony of Company Witness Nathan J. Frost, the Company plans to deploy a prepay program that will allow customers to more closely manage their energy consumption by establishing self-imposed limits on energy consumption by prepaying their electric utility bill. Published studies of prepay programs have shown energy and demand reductions for customers that use this program. The energy and demand savings of prepay, which are calculated based on an assumed escalation of adoption following the full implementation of AMI, eventually peaking at 5% of eligible customers. The projected benefit modeled to begin in 2026 of 10% reduction of energy usage, and 0.5% reduction in demand are based on steady-state assumptions, conservatively estimated from similar prepay program results from across the country. The resulting reduction in energy and demand due to prepay are multiplied by the costs of energy and demand for each year to calculate demand savings. The resulting benefit projection can be found in my Schedule 2.

As described by Company Witness Robert S. Wright, voltage optimization investments will also drive energy and demand savings. The projected savings in this area were provided by the Company and incorporated into the CBA, modeled to begin in 2022.

Q. Does the Company expect to realize energy and demand benefits related to the availability of interval energy usage data for customers via AMI and the customer information platform ("CIP"), including expanded digital customer channels?

A. Yes, benefits have been captured in this area. As noted in the direct testimony of Company Witnesses Nathan J. Frost and Thomas J. Arruda, the Company plans to deploy AMI and a modernized CIP that includes enablement of advanced channels of communication with customers. Among the information that will be accessible to customers via the CIP is the presentation of the interval energy usage data that is made available via AMI. The CIP also enables additional alerting and notification options. Research has shown that customers with AMI meters and enhanced customer portals reduce their energy consumption. The benefit calculation incorporates the percentage of customers that are expected to actively engage with and leverage the additional information, as well as the percentage of energy usage that will decline as a result of that engagement and change in behavior. Within the CBA, it is projected that 5.8% of customers will be actively engaged and adjusting their behavior, and that the impact of that will be a 1.1% reduction in energy usage in the steady state, following AMI and CIP deployment.

Q. What is the overall benefit projection for energy / demand savings associated with the GT Plan?

A. As noted in Figure 1, the total benefits associated with energy / demand benefit are approximately $238 million (NPV) over the asset life of the proposed investments.

Q. Focusing on the EV-related benefits that you discussed, what work was done to project additional EV ownership savings associated with Transportation Electrification?

A. As discussed by Company Witness Frost, the Company proposes to provide incentives to manage charging and deploy EV charging stations in furtherance of future intelligent and managed charging program in response to the expected levels of EV adoption. A study performed by Navigant Consulting, Inc. provided to the Company and West Monroe focused on Virginia and the Company's service territory and anticipates the steady increase in the penetration of EVs over the next 20 years and beyond. As a result of the Company's investments in infrastructure and programs, EV owners will be better positioned to save money on their transportation costs by shifting from gas to electric as the source of power. Additionally, electricity is a more environmentally friendly source of fuel as compared to gasoline.

The calculation of benefits in this area is done by comparing the cost of electricity needed to power the projected EVs to the cost of gasoline for an equivalent number of miles driven. The detail used for this calculation includes the number of EVs projected, the projected number of EV miles driven, the total dollars that would have been spent on gasoline for the same number of miles driven, the cost of electricity for the EV miles driven (7,800 miles annually based on industry benchmarking), the energy savings from the conversion to EVs, and the portion of those savings that are reasonably attributable to the Company's programs and investments as part of GT Plan.

Q. What was the calculation method for the difference in customer spend on gas-powered vehicles versus electric vehicles?

A. The average miles per gallon forecast provided by the Environmental Protection Agency ("EPA") was multiplied by the forecasted cost of gasoline to calculate the customer spend on gas-powered vehicles. Consumer costs for EV miles driven was then calculated by taking the number of EV miles driven and the forecasted miles per kilowatt-hour ("kWh") and multiplying by the forecasted cost of electricity. The benefit is then calculated by subtracting the costs of EV "fuel" (*i.e.*, electricity) from the costs for gas-powered vehicles for the same number of miles.

Q. Can the Company be reasonably credited with driving all of the projected proliferation of EVs in the Company's service territory, and therefore all of the projected EV Ownership Savings benefits?

A. No, and the CBA has not captured (or taken credit for) the full value of benefits associated with EV ownership. There are customers that have and will continue to purchase EVs irrespective of any planned investments or programs in the GT Plan. However, by installing additional charging stations and offering programs such as managed charging, the growth of EVs will be accelerated by limiting the customer concern associated with a lack of charging infrastructure (*i.e.*, "range anxiety") and positioning them to save money. The Institute for Physics published a paper in July of 2017, titled "The Role of Demand-Side Incentives and Charging Infrastructure on Plug-In EV adoption: Analysis of US States,"[1] which forecasted the relationship of public charging accessibility to increased adoption of EVs. The research demonstrated the

[1] https://iopscience.iop.org/article/10.1088/1748-9326/aad0f8.

impacts of the public charging stations funded by the American Recovery and Reinvestment Act deployed between 2011 and 2014 of roughly $40 million. The study showed that the EV penetration rate can be increased between 2.3% to 9.75%, based on the type of vehicle and whether enough public charging stations are available to address "range anxiety." In cases where there was deemed to be sufficient public charging stations deployed, the average improvement in EV sales was 7.2%. There are additional studies and research papers that suggest a higher correlation between infrastructure investment program availability, and greater EV sales.

All that said, the portion of EV energy savings and the corresponding GHG reductions associated with EV use was derived by taking the total EV energy and EV GHG savings and multiplying it by 7.2%.[2] The total benefits calculated for EV Ownership Savings and GHG savings related to EV ownership are displayed on lines 46 and 9, respectively of my Schedule 3.

<u>(4) Total Improved Reliability Benefit</u>

Q. Please explain how the benefits associated with total improved reliability benefit as presented in the CBA were derived.

A. There are several sources of the reliability improvements in the GT Plan described by Company Witness Wright, including Self-healing Grid, Outage Management System improvements with AMI, Enterprise Asset Management System, Proactive Component Upgrades, and Grid Hardening. For each of these areas, the Company provided specific reliability improvement projections based on the detailed scopes of work and engineering

[2] This conservative adjustment was applied to only these components of the EV benefits captured within the model. The other EV Benefits captured are not applicable to this factor.

exercises that were completed in the form of reduced customer interruptions ("CI") and customer minutes of interruption ("CMI") based upon the specific project and the number of customers directly impacted. Since the analysis focused on specific equipment in the system, the exact number and type of customers that would see a direct benefit of each specific project was captured.

West Monroe then input this Company-specific information into the United States Department of Energy Interruption Cost Estimate ("ICE") Model, version March 2018, to calculate the value of the improved reliability benefits to customers in dollar form. The resulting calculation captured the aggregate benefits from each type of reliability improvement by year in the CBA and were included in the CBA based on the timing of planned GT Plan investments and the asset life of the related assets that drive the benefit.

As noted in Figure 1, the total benefits associated with improved reliability benefit are estimated to be approximately $2.0 billion (NPV) over the asset life of the proposed investments.

Q. Is the DOE ICE model a reasonable method for quantifying reliability benefits?

A. Yes. Lawrence Berkeley National Laboratory created the model for the DOE as a means to identify the value of service reliability for electricity customers in the United States. The DOE ICE model quantifies the economic benefit from improvements in system average interruption duration index ("SAIDI") and system average interruption frequency index ("SAIFI") to key customer segments for utilities based on their size and region in a consistent and transparent fashion. The DOE ICE model is accepted in the industry as a dependable source for reliability benefit valuation and has gone through several iterations since being introduced about a decade ago, including the latest update in March 2018.

The ICE model creates state specific estimates of electric system reliability improvements for each of the 50 states in the US, including the Commonwealth of Virginia. The ICE model leverages 34 Cost Interruption Studies from 10 different utilities that were executed between 1989 and 2012. Notably, 3 of these 10 utilities were from the southeast. The model has taken the information from these studies to estimate the value of reliability to different types and sizes of commercial and industrial customers, as well as for residential customers. The model uses the state input information to determine the appropriate mix of these different types and sizes of commercial and industrial customers based on an analysis of the business Standard Industrial Classification codes. The 2018 version of the DOE ICE model has been updated to improve the accuracy of the reliability calculations by also taking into consideration the state gross domestic product ("GDP"). The researchers have found that that the higher the state GDP the more important electric reliability is to the customers, especially for the businesses. Additional information on the model and the calculation methods used to correlate reliability improvements to customer economic impacts can be found at www.icecalculator.com.

Many utilities have used the DOE ICE model to translate specific customer reliability improvements in the form of SAIDI and SAIFI to customer financial benefits, which are found in technical literature, industry conference presentations, and utility fillings.

It is important to note that as part of the detailed planning and engineering work referenced by Company Witness Wright, the Company completed a detailed analysis that identifies key system components impacted, including the nature and state of the distribution infrastructure, historical reliability performance, and customer impacts. The resulting GT Plan targets those feeders and segments of the grid that will provide the largest opportunity for benefit delivery to as many customers as possible, which is then translated to customer financial benefits through the output of the ICE model.

<u>(5) Total Reduction of Bad Debt and Energy Diversion</u>

Q. Finally, please explain how the benefits associated with total reduction of bad debt and energy diversion as presented in the CBA were derived.

A. West Monroe worked with the Company to identify the current and projected levels of customer bad debt that the Company must write-off, and energy diversion associated with meter tampering. By leveraging the functionality of AMI, specifically use of the remote connect and disconnect switch, and the ability to more accurately identify meter tampering activities or the identification of malfunctioning equipment, utilities across the country have experienced significant reductions in bad debt expense and energy diversion. Projected savings for Dominion Energy Virginia were based on similar programs and technology deployments, and as noted in Figure 1, the total benefits associated with bad debt and energy diversion are approximately $119 million (NPV) over the asset life of the proposed investments.

Q. You have mentioned that a conservative approach was taken to many of the benefits assumptions used to complete the CBA. Why is that?

A. There are several reasons why it is more appropriate and prudent to conservatively estimate benefit components of the CBA. First, many of the planned investments within GT Plan are foundational by nature, and not yet installed. Because of this, and given the unique nature of any company's service territory, it is appropriate to take a measured approach to projecting elements of the analysis that drive certain benefits, particularly those associated with customer behavior and program adoption. For this reason, a blend of industry benchmarking and Company history with customer programs were used to develop certain benefit projections. For instance, there are examples across the country of the adoption in time-varying rates and peak time rebate programs; West Monroe used adoption levels on the low end of industry experience for the projects in the CBA. It is important to note that even with the more conservative benefit assumptions, the overall GT Plan remains cost beneficial due to the wide range of impactful benefits that are delivered via the planned investments.

III. ADDITIONAL GT PLAN BENEFITS

Q. Please explain why certain benefits were not included in the "total" for the CBA NPV calculation, and are instead listed as "additional."

A. While West Monroe and the Company are confident in the value of GT Plan benefits that are not classified as "Customer Benefits," it was deemed appropriate to exclude them from the initial NPV and benefit/cost ratio in order to provide a customer-focused assessment of the planned investments. Again, for reference, the additional benefits include reduction in GHG, EV ownership savings, referenced in my testimony above, and overall economic impact of the planned investments.

Q. What work was done to project GHG reduction benefits associated with GT Plan investments?

A. The projects that reduce the consumption of electricity, as described and quantified earlier in this testimony, also result in lower emissions due to the reduction in electricity generation. Other GTP programs reduce the amount of GHG created from vehicles, which include utility vehicle GHG reduction due to lower truck rolls and the reduction of GHG due to EV adoption. Two separate calculations were made to capture the reduction in greenhouse gas emissions: 1) reduced miles travelled in gasoline/diesel vehicle, and 2) impact due to reduced MWh of electricity generation. The Company provided inputs and data points to West Monroe to then calculate these GHG reductions.

The deployment of AMI meters results in a reduction in fleet requirements, both for AMR meter reading that is eliminated and for a wide range of orders executed by the field services function. Planned investments in Self-healing Grid, Outage Management, and Main Feeder Hardening also have an impact in this area. The resulting reduction in miles driven by utility personnel results in a reduction of GHG emissions.

The GHG impact of reduced MWh electricity generation was calculated for other programs, such as deployment of time-varying rates and programs, and voltage optimization. Lastly, GHG emissions reductions are calculated for Transportation Electrification by comparing the GHG emissions from conventional vehicles to GHG emissions from electricity generation needed to charge EVs.

DOE measurements and data points were leveraged to derive the estimated tons of GHG emissions per megawatt-hour ("MWh") of electricity generated, which was converted to calculate avoided electricity to GHG savings. The total GHG benefit is calculated by taking the amount of reduced GHG emissions and multiplying it by the forecasted value of GHG emissions, also known as the social cost of carbon. The categories and details associated with projected reductions in GHG emissions are captured in my Schedule 3.

Q. What method was used to calculate the economic impact of the GT Plan investments?

A. The Company worked with West Monroe to develop the projected impact of the GT Plan on the economy, including creation of jobs and overall stimulus. As shown in Figure 1, the additional benefit associated with the economic impact of the GT Plan is approximately $2.8 billion (NPV).

Q. Please provide additional detail on the estimate for total economic impact associated with the Company's proposed GT Plan projects?

A. The Bureau of Economic Analysis ("BEA") Regional Input-Output Modeling System II ("RIMS II") approach was used to estimate the economic impact based on a capital multiplier that is specific to the region. The economic impact calculation is based on regional economy-wide impacts of the BEA RIMS II approach. The BEA is a United States government organization that is responsible for the creation of official economic statistics, which provide a comprehensive and up-to-date picture of the United States economy and are used to aid businesses, policy makers, and households. The local and state impact of the GT Plan on direct and indirect job growth will have a positive impact on the overall state economy in Virginia. The overall economic impact, like the indirect jobs impact, benefits the overall United States economy in addition to the Commonwealth of Virginia. As noted above, these economic benefits have been calculated and are not included in the "total" CBA, but are noted as "additional" benefits for Commission consideration.

Q. **Regarding economic impact, how many new jobs are estimated to be created as a result of the proposed GT Plan investments and how was that estimate derived?**

A. For the purposes of this analysis and testimony, a job is defined as a resource working full time for one year. Direct jobs are those that result from people working on a GT Plan project, and indirect jobs are those that result from increased economic activity as a result of the planned investments (*i.e.*, suppliers, other service providers, etc.).

Over a 20-year period, the BEA RIMS II Model projects that approximately 4,500 direct and 17,000 indirect jobs will be created as a result of the proposed GT Plan investments. Direct jobs are expected to be high-paying, technology-oriented positions that will enable economic growth and stability, while providing rewarding and developmental opportunities to a growing workforce. Indirect jobs, such those associated with restaurants, hotels, and construction are based on a capital multiplier that is specific to the region.

Q. **Are there further benefits that are not easily quantified in terms of economic value?**

A. Yes, there are. One prime example is the significant improvement to the customer experience that will be delivered by the GT Plan. The increased level of customer choice, engagement, and satisfaction of customers that will result from these investments, particularly those in the areas of CIP and AMI are difficult to assign a value to, but the Company is confident that they are real and in alignment with what customers are demanding. The GT Plan will also improve the overall operating condition of the distribution grid resulting in improvements to safety of both customers and employees. This is also difficult to specifically quantify, but the Company is confident that this critical area will be positively impacted by the GT Plan. Another area of benefit that is not specifically captured is the reliability improvements associated with targeted corridor improvements. The specific and targeted activities planned for selected corridors to pro-actively address areas where excess vegetative growth can cause system delays, outages, and other operational issues will drive improvements to reliability, but the specific values were not able to be isolated and projected to a level of certainty, and are therefore not included in the CBA. Although the Company has not attempted to quantify these benefits in this case to remain conservative, they further demonstrate that the business case is positive and that the planned investments are prudent.

Q. Are there specific projected benefits associated with the planned investments in Advanced Analytics?

A. The Company has not allocated specific benefits to the deployment of Advanced Analytics as this investment enabled the quantified benefits already allocated to other areas of the GT Plan. As noted throughout Company testimony, and specifically with Company Witness Wright's areas of focus, the planned investments in Advanced Analytics have a wide range of impacts and will drive value across the organization. The benefits planned to be delivered in other areas would not be realized without the Advanced Analytics investments. Data coming from AMI and other intelligent grid devices and control systems will be leveraged by the Advanced Analytics platform and organization in the development of specific use cases and reporting that will drive efficiencies and improvements in operations. Actionable output from the Advanced Analytics organization will also prevent the erosion of benefits over time by identifying data trends, required process changes, and prioritized activities to ensure that systems and equipment are performing at their anticipated levels, and that benefits delivery continues at the projected levels, or at enhanced levels.

IV. OBSOLESCENCE CONSIDERATIONS

Q. Based on your industry experience, what concerns should utilities have regarding the potential for premature obsolescence of Grid Transformation-related technologies and investments?

A. Public utilities should always carefully weigh and consider investments, especially large-scale capital expenditures, using a number of lenses, including consideration of possible obsolescence of technology. It is important to maintain flexibility and forward-compatibility as key criteria for the selection of software, hardware, and other field devices associated with the continued modernization of the grid.

Dominion Energy Virginia has demonstrated that these are priorities, via their plans to leverage cloud-based solutions for software and leveraging an iterative planning and implementation process for field devices and other technologies that rely on the ongoing assessment of new and emerging capabilities that deliver the desired functionality and targeted customer benefits. West Monroe has seen, first-hand, the value that the Company places on forward compatibility of the planned investments during vendor evaluation and the planning process and believes that the investments within the GT Plan will deliver long-lasting and sustainable benefits consistent with the CBA.

Q. Specifically, what is West Monroe's perspective on the potential premature obsolescence of the Company's proposed AMI technology?

A. There are several reasons why this concern has been addressed, including specific technology features and capabilities of the AMI solution that has been selected. The main feature of AMI technology that addresses this concern is the ability to leverage the communication network to update the meter and firmware (the software programmed into each meter) remotely, also known as "over the air" programing, allowing the Company to stay current on updates that deliver improvements and enhancements to the AMI system and the smart meters. This technology capability of "over the air" programing prolongs the useful life of the entire solution, from meters through the communication devices and network technology, positioning the Company to operate a long-term, flexible, and dependable AMI solution. Additionally, there is feedback and analysis on this specific topic by multiple third parties and industry researchers that has conclusively addressed this concern.

The status of AMI Deployment across the United States and the Company's past experience with solid-state meters that have communications devices also provides evidence and support that this technology is not at risk of near-term obsolescence. This information and more can be referenced in a white paper authored by West Monroe, attached as my Schedule 5, which outlines our perspective on this topic.

Q. Please summarize your testimony.

A. West Monroe worked closely with the Company to identify the required inputs, assumptions, data points, and deployment timelines associated with the GT Plan that would enable accurate projection of the associated and comprehensive costs and benefits. This information was input into the established CBA methodology for analysis.

The CBA demonstrates that the GT Plan investments are cost beneficial. The planned investments deliver significant benefit to all customers across a wide range of areas, while also driving reductions in greenhouse gas emissions, increase in new jobs and economic growth in the Commonwealth, and savings to EV owners.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

BACKGROUND AND QUALIFICATIONS OF THOMAS G. HULSEBOSCH

Tom Hulsebosch is a member of the Executive Leadership team and serves on the Board of Directors of West Monroe Partners. West Monroe is a management and technology consulting firm with over 1300 employees in 10 offices across the United States. Tom leads the firm's Energy & Utilities practice as well as the Dallas Office.

Tom is a 30-year veteran of the utility, ISP, and wireless telecommunication industries, with extensive experience creating and delivering solutions for utilities, enterprises, cities, and service providers. Over the past twelve years, Tom has been driving innovative smart grid, smart community, and sustainability programs for utilities and cities along with other key industry stake holders such universities, National Laboratories, and the US Department of Energy.

Tom has a Bachelor of Science in Electrical Engineering from Marquette University in Milwaukee and a Master of Science in Electrical Engineering from the Illinois Institute of Technology in Chicago. Tom also holds seven US Patents. In 2015, Tom was recognized as one of the Top 25 Consultants in the US for his work in Energy by Consulting Magazine.

Tom has performed the role of smart-utility architect for several utilities going through the transformation that is associated with major business process, technology, and business model changes. This includes creating smart-utility strategy, selecting the best technology, identifying the new business model, quantifying the benefits, creating the business case, optimizing the deployment plan, selecting vendors, integrating systems, and providing deployment support. In addition, Tom has guided the technology procurement process for many types of utility telecommunication solutions, smart-grid applications, and smart metering equipment for a variety of water, gas, and electric utilities.

Tom joined West Monroe Partners in 2008 from Strategy 2 Solution, LLC, a consulting firm that he founded. He led Strategy 2 Solution's consulting practice, which focused on developing executable and sustainable wireless network solutions for municipalities, utilities, corporations, and service providers, as well as creating product strategies and sales distribution solutions for equipment vendors. Prior to starting Strategy 2 Solution, Tom was the vice president of municipal network sales for EarthLink Municipal Networks. Tom also spent nearly 20 years with Motorola performing a variety of sales, strategy, marketing, product management, and engineering roles.

Capital Expenditures Summary (Total)

(Nominal dollars, in millions)

	2019 Yr 1	2020 Yr 2	2021 Yr 3	3-yr Total	10-yr Total
Advanced Metering Infrastructure (AMI)	$14.9	$71.9	$100.3	$187.0	$394.4
Customer Information Platform / Meter Data Management (CIP/MDM)	$7.3	$38.4	$45.2	$90.8	$197.7
Time-Varying Rates	-	$0.5	-	$0.5	$0.5
Peak-Time Rebate	-	-	-	-	$0.1
Prepay	-	-	-	-	$21.6
Stakeholder Engagement & Customer Education	-	-	-	-	-
Telecommunications	$6.4	$65.2	$66.0	$137.6	$453.2
Grid Technologies	$2.5	$31.9	$21.3	$55.6	$452.0
Grid Hardening	$2.2	$20.9	$61.3	$84.5	$1,233.2
Cyber Security	-	$2.9	$1.9	$4.8	$20.9
Physical Security	$0.9	$3.5	$3.5	$7.9	$50.7
Transportation Electrification *(All Programs)*	-	$1.5	$2.4	$3.8	$7.3
Total Capital Expenditures:	$34.0	$236.5	$301.9	$572.4	$2,831.7
Total Capital Expenditures (Phase 1B):	$26.8	$218.9	$265.4	$511.0	

Projected Capital Expenditures inclusive of GTP and non-GTP programs

2095002

O&M Expenditures Summary (Total)

(Nominal dollars, in millions)

	2019	2020	2021		
	Yr 1	Yr 2	Yr 3	3-yr Total	10-yr Total
Advanced Metering Infrastructure (AMI)	$1.9	$3.0	$4.6	$9.6	$53.9
Customer Information Platform / Meter Data Management (CIP/MDM)	$4.2	$8.7	$10.8	$23.7	$160.3
Time-Varying Rates	-	$0.7	$0.7	$1.4	$8.6
Peak-Time Rebate	-	-	-	-	$7.7
Prepay	-	-	-	-	$1.6
Stakeholder Engagement & Customer Education	$0.0	$1.4	$1.8	$3.2	$11.1
Telecommunications	$1.2	$2.3	$2.9	$6.3	$74.4
Grid Technologies	-	$1.1	$1.8	$2.9	$45.2
Grid Hardening	$6.0	$6.2	$8.1	$20.3	$36.7
Cyber Security	-	$0.9	$1.4	$2.3	$32.1
Physical Security	$0.0	$0.1	$0.2	$0.3	$5.2
Transportation Electrification *(All Programs)*	$0.4	$5.3	$11.4	$17.1	$42.9
Total O&M Expenditures:	$13.8	$29.7	$43.6	$87.1	$479.6
Total O&M Expenditures (Phase 1B):	$12.6	$29.5	$43.1	$85.2	

Projected Operating Expenditures inclusive of GTP and non-GTP programs

Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Present Value Asset Life Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Customer Benefits						
2	Total Avoided/Deferred Capital		$ 657,720	$ 8,283,975	$ 10,235,580	$ 375,638,589	Line 10
3	Total O&M Savings		$ -	$ 2,081,834	$ 5,843,195	$ 265,914,344	Line 100
4	Total Energy/Demand Benefit		$ -	$ 80,292	$ 166,512	$ 237,538,720	Line 200
5	Total Improved Reliability Benefit		$ -	$ -	$ 13,357,319	$ 2,028,116,192	Line 239
6	Total Reduction of Bad Debt & Energy Diversion		$ 1,230,830	$ 2,250,491	$ 4,999,690	$ 118,887,075	Line 276
7	Total Customer Benefits		$ 1,888,550	$ 12,696,592	$ 34,602,296	$ 3,026,094,921	Sum Lines 2-6
8							
9							
10	Avoided/Deferred Capital Benefit Detail		$ 657,720	$ 8,283,975	$ 10,235,580	$ 375,638,589	Sum Lines 12-95
11							
12	Avoided AMR/Walk-Up Equipment Upgrade/Replacement (AMI)	Nate Frost	$ 72,720	$ 1,012,909	$ 74,249	$ 2,986,205	Sum Lines 13-18
19							
20	Avoided AMR Meter Replacement (AMI)	Nate Frost	$ 585,000	$ 2,288,025	$ 4,786,211	$ 66,712,729	Line 21*Line 22
23							
24	Avoided CBMS Mainframe Capital Maintenance (CIP)	Thomas Arruda	$ -	$ -	$ -	$ 2,604,928	Sum Lines 25-27
28							
29	Avoided Capital Run Rate (CIP)	Thomas Arruda	$ -	$ 4,528,149	$ 4,671,806	$ 35,920,194	Sum Lines 30-32
33							
34	Avoided T&D Upgrade Investment (Time-Varying Rates)	Greg Morgan	$ -	$ 55,070	$ 110,242	$ 7,066,693	Line 35*Line 36
37							
38	Avoided T&D Upgrade Investment (PTR)	Tom Hulsebosch	$ -	$ -	$ -	$ 15,983,255	Line 39*Line 40
41							
42	Avoided T&D Upgrade Investment (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 99,602	Line 43*Line 44
45							
46	Reduction in Future Capital from Carrier Cellular costs (Telecom)	Bradley Carroll	$ -	$ 20,467	$ 20,915	$ 330,664	Line 47*Line 48
49							
50	Avoided T&D Upgrade Investment (Voltage Optimization)	Robert Wright	$ -	$ -	$ -	$ 11,914,382	Line 51*Line 52
53							
54	Avoided Mainfeeder Maintenance - Capital Maintenance (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 4,641	$ 2,512,143	*Dominion Projection*
55							
56	Avoided Mainfeeder Outage Truck Roll - Capital Maintenance (Mainfeeder Hardening)	Robert Wright	$ -	$ 1,095	$ 3,249	$ 639,961	Line 57*Line 58*Line 59
60							
61	Avoided Mainfeeder Storm Outage Truck roll - Capital Maintenance (Mainfeeder Hardening)	Robert Wright	$ -	$ 127	$ 266	$ 59,030	Line 62*Line 63*Line 64
65							
66	Avoided Mainfeeder Storm Pole Replacements - Capital (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 11,546	$ 2,252,516	*Dominion Projection*
67							
68	Avoided Outage Truck Rolls - Capital Maintenance (Targeted Corridor Improvement)	Robert Wright	$ -	$ 95,559	$ 98,590	$ 333,062	Line 69*Line 70*Line 71
72							
73	Avoided Service Transformer Overload Failure - Capital Maintenance (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ 5,871	$ 248,822	Line 74*Line 75*Line 76
77							
78	Avoided Poor Health Transformer Replacement (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 171,027,338	Line 79*Line 80
81							
82	Avoided Poor Health Transformer Outage - Capital Maintenance (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 4,442	Line 83*Line 84*Line 85
86							
87	APM - Deferred Capital Spend (EAMS)	Robert Wright	$ -	$ -	$ -	$ 2,902,263	Line 88*Line 89
90							
91	Centralized Inventory - Avoided Capital Spend (EAMS)	Robert Wright	$ -	$ -	$ -	$ 818,920	Line 92*Line 93
94							
95	Avoided T&D Upgrade Investment (Transportation Electrification)	Nate Frost	$ -	$ 282,576	$ 447,992	$ 51,221,438	Line 96*Line 97
98							
99							
100	O&M Savings Benefit Detail		$ -	$ 2,081,834	$ 5,843,195	$ 265,914,344	Sum Lines 102-191
101							
102	Reduction in AMR Meter Reading Expense (AMI)	Nate Frost	$ -	$ 244,102	$ 2,165,817	$ 102,376,399	Sum Lines 103, 104
105							
106	Reduction in Meter Servicing Expense (AMI)	Nate Frost	$ -	$ 112,147	$ 995,221	$ 47,111,666	Sum Lines 107, 108
109							
110	Reduction in 'Found On' Operations Expense (AMI)	Nate Frost	$ -	$ 30,615	$ 269,528	$ 11,986,036	(Line 112 - Line 113)*Line 111
114							
115	Reduction in Meter Re-Reads (AMI)	Nate Frost	$ -	$ 3,472	$ 6,410	$ 177,494	Line 116*Line 117*Line 118
119							
120	Billing Process Improvement Benefits (AMI)	Nate Frost	$ -	$ 57,312	$ 105,800	$ 2,929,771	*Dominion Projection*
121							
122	Reduction in Customer Calls (AMI)	Nate Frost	$ -	$ 243,597	$ 449,689	$ 12,452,652	Line 123*Line 124*Line 125*Line 126
127							
128	Billing Process Improvement Benefits (CIP)	Thomas Arruda	$ -	$ -	$ -	$ 813,175	*Dominion Projection*

Company Exhibit No. __
Witness: TGH
Schedule 2
Page 1 of 3

Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Present Value Asset Life Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
129							
130	Avoided CBMS Mainframe Maintenance Expense (CIP)	Thomas Arruda	$ -	$ -	$ -	$ 25,943,557	Sum Lines 131-133
134							
135	CSR Savings (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 319,961	Line 136*Line 137*Line 138*Line 139*Line 140
141							
142	Reduction in O&M from Leased MPLS costs (Telecom)	Bradley Carroll	$ -	$ 90,922	$ 334,137	$ 26,847,841	Line 143*Line 144
145							
146	Reduction in Future O&M from Carrier Cellular costs (Telecom)	Bradley Carroll	$ -	$ 720	$ 1,440	$ 99,503	Line 147*Line 148
149							
150	Total Avoided Capital and O&M costs for New Leased LTE (Telecom)	Bradley Carroll	$ -	$ 13,151	$ 78,905	$ 2,414,386	Line 151*Line 152
153							
154	Avoided Mainfeeder Maintenance (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 1,703	$ 851,301	*Dominion Projection*
155							
156	Avoided Mainfeeder Outage Truck Rolls (Mainfeeder Hardening)	Robert Wright	$ -	$ 14,542	$ 43,163	$ 8,502,336	Line 157*Line 158*Line 159
160							
161	Avoided Mainfeeder Storm Outage Truck Rolls (Mainfeeder Hardening)	Robert Wright	$ -	$ 1,689	$ 3,540	$ 8,502,336	Line 162*Line 163*Line 164
165							
166	Avoided Corridor Improvement Outage Truck Rolls (Targeted Corridor Improvement)	Robert Wright	$ -	$ 1,269,567	$ 1,309,845	$ 4,424,966	Line 167*Line 168*Line 169
170							
171	Avoided Transformer Overload Failure Maintenance (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ 78,000	$ 3,305,783	Line 172*Line 173*Line 174
175							
176	THA - Avoided Transformer Outage Maintenance (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 59,018	Line 177*Line 178*Line 179
180							
181	APM - Labor Savings (EAMS)	Robert Wright	$ -	$ -	$ -	$ 2,068,227	Line 182*Line 183*Line 184
185							
186	APM - Recovery of Warranty Leakage (EAMS)	Robert Wright	$ -	$ -	$ -	$ 127,420	Line 187*Line 188*Line 189
190							
191	EWP - Labor Savings (EAMS)	Robert Wright	$ -	$ -	$ -	$ 4,600,518	Sum Lines 192-197
198							
199							
200	Energy & Demand Savings Benefit Detail		$ -	$ 80,292	$ 166,512	$ 237,538,720	Sum Lines 202-220
201							
202	Energy Reduction (AMI)	Nate Frost	$ -	$ -	$ -	$ 3,560,644	*Dominion Projection*
203							
204	Avoided Energy Cost (Time-Varying Rates)	Greg Morgan	$ -	$ 5,808	$ 16,796	$ 3,942,435	Sum Lines 205, 206
207							
208	Avoided Demand Cost (Time-Varying Rates)	Greg Morgan	$ -	$ 7,478	$ 29,533	$ 12,729,008	Line 209*Line 210
211							
212	Avoided Energy Cost (Opt-In) (PTR)	Tom Hulsebosch	$ -	$ -	$ -	$ 274,507	Sum Lines 213-216
217							
218	Avoided Demand Cost (Opt-In) (PTR)	Tom Hulsebosch	$ -	$ -	$ -	$ 46,284,013	Sum Lines 219, 220
221							
222	Avoided Energy Cost (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 10,611,700	Line 223*Line 224
225							
226	Avoided Demand Cost (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 3,299,081	Line 227*Line 228
229							
230	Energy Reduction (Voltage Optimization)	Robert Wright	$ -	$ -	$ -	$ 103,021,325	*Dominion Projection*
231							
232	Demand Reduction (Voltage Optimization)	Robert Wright	$ -	$ -	$ -	$ 33,754,882	*Dominion Projection*
233							
234	Energy Savings from Managed Charging (Transportation Electrification)	Nate Frost	$ -	$ 28,636	$ 40,148	$ 3,481,746	*Dominion Projection*
235							
236	Capacity Savings from Managed Charging (Transportation Electrification)	Nate Frost	$ -	$ 38,370	$ 80,035	$ 16,579,380	*Dominion Projection*
237							
238							
239	Improved Reliability Benefit Detail		$ -	$ -	$ 13,357,319	$ 2,028,116,192	Sum Lines 241-273
240							
241	Annual Residential Customer Benefit from Reduced Outages (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 228,307	$ 37,090,003	*Dominion Projection*
242							
243	Annual Small C&I Customer Benefit from Reduced Outages (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 2,117,363	$ 300,478,213	*Dominion Projection*
244							
245	Annual Large C&I Customer Benefit from Reduced Outages (Mainfeeder Hardening)	Robert Wright	$ -	$ -	$ 329,248	$ 141,732,742	*Dominion Projection*
246							
247	Service Transformer - Reliability Benefit (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ 6,456,778	$ 192,715,536	Sum Lines 248-250
251							
252	THA Transformer - Reliability Benefit (Proactive Component Upgrades)	Robert Wright	$ -	$ -	$ -	$ 161,059,243	Sum Lines 253-255
256							
257	Residential Reliability Benefits (EAMS)	Robert Wright	$ -	$ -	$ -	$ 1,765,647	*Dominion Projection*

Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Present Value Asset Life Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
258							
259	Small C&I Reliability Benefits (EAMS)	Robert Wright	$ -	$ -	$ -	$ 11,645,321	*Dominion Projection*
260							
261	Large C&I Reliability Benefits (EAMS)	Robert Wright	$ -	$ -	$ -	$ 126,524,322	*Dominion Projection*
262							
263	Residential Reliability Benefits (Self-Healing Grid)	Robert Wright	$ -	$ -	$ 404,068	$ 62,505,348	*Dominion Projection*
264							
265	Small C&I Reliability Benefits (Self-Healing Grid)	Robert Wright	$ -	$ -	$ 3,274,784	$ 552,300,281	*Dominion Projection*
266							
267	Large C&I Reliability Benefits (Self-Healing Grid)	Robert Wright	$ -	$ -	$ 546,770	$ 266,750,062	*Dominion Projection*
268							
269	Residential Reliability Benefits (OMS)	Robert Wright	$ -	$ -	$ -	$ 1,831,271	*Dominion Projection*
270							
271	Small C&I Reliability Benefits (OMS)	Robert Wright	$ -	$ -	$ -	$ 12,116,410	*Dominion Projection*
272							
273	Large C&I Reliability Benefits (OMS)	Robert Wright	$ -	$ -	$ -	$ 159,601,793	*Dominion Projection*
274							
275							
276	Bad Debt & Energy Diversion Reduction Benefit Detail		$ 1,230,830	$ 2,250,491	$ 4,999,690	$ 118,887,075	Sum Lines 278-291
277							
278	Bad Debt Reduction (AMI)	Nate Frost	$ -	$ 119,112	$ 1,471,532	$ 58,142,907	Sum Lines 279, 280
281							
282	Theft/Energy Diversion Recovery (AMI)	Nate Frost	$ 1,092,326	$ 1,973,214	$ 3,238,671	$ 52,163,086	Line 283*Line 284
285							
286	Meter Accuracy Improvement (AMI)	Nate Frost	$ 138,504	$ 158,165	$ 289,487	$ 8,220,363	Line 287*Line 288*Line 289
290							
291	Reduction of Uncollectable (Prepay)	Tom Hulsebosch	$ -	$ -	$ -	$ 360,718	(Line 293/Line 292)*Line 294*Line 295
296							

Line No.	Description	Sponsoring Witness	2019 Yr 1	2020 Yr 2	2021 Yr 3	Present Value Asset Life Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	**Additional Benefits**						
2	Total Reduced Greenhouse Gas Emissions Benefit		$ 23,821	$ 30,252	$ 40,468	$ 4,051,014	Line 7
3	Total Customer Pocketbook Savings		$ 112,812	$ 1,631,694	$ 2,081,824	$ 81,222,166	Line 44
4	Total Additional Benefits		$ 136,633	$ 1,661,945	$ 2,122,292	$ 85,273,180	Sum Lines 2-3
5							
6							
7	Reduced Greenhouse Gas Emissions Benefit Detail		$ 23,821	$ 30,252	$ 40,468	$ 4,051,014	Sum Lines 9-40
8							
9	Reduced GHG Benefits (Adjusted as Effect of Lift) (Transportation Electrification)	Nate Frost/Tom Hulsebosch	$ 23,549	$ 29,663	$ 38,441	$ 1,324,247	Line 10*Line 11
12							
13	Reduced GHG Benefits (AMI)	Nate Frost/Tom Hulsebosch	$ -	$ 143	$ 1,225	$ 40,169	Line 14*Sum Lines 15-18
19							
20	Reduced GHG Benefits (Time-Varying Rates)	Greg Morgan/Tom Hulsebosch	$ -	$ 174	$ 530	$ 143,437	Line 21*Line 22
23							
24	Reduced GHG Benefits (PTR)	Greg Morgan/Tom Hulsebosch	$ -	$ -	$ -	$ 1,309	Line 25*Line 26
27							
28	Reduced GHG Benefits (Prepay)	Greg Morgan/Tom Hulsebosch	$ -	$ -	$ -	$ 171,812	Line 29*Line 30
31							
32	Reduced GHG Benefits (Self-Healing Grid)	Robert Wright/Tom Hulsebosch	$ 272	$ 272	$ 272	$ 3,638	Line 33*Line 34
35							
36	Reduced GHG Benefits (OMS)	Robert Wright/Tom Hulsebosch	$ -	$ -	$ -	$ 1,370	Line 37*Line 38
39							
40	Reduced GHG Benefits (Voltage Optimization)	Robert Wright/Tom Hulsebosch	$ -	$ -	$ -	$ 2,365,031	Line 41*Line 42
43							
44	EV Ownership Savings		$ 112,812	$ 1,631,694	$ 2,081,824	$ 81,222,166	Line 46
45							
46	EV Ownership Savings (Transportation Electrification)	Nate Frost/Tom Hulsebosch	$ 112,812	$ 1,631,694	$ 2,081,824	$ 81,222,166	Sum Lines 47-49
50							

Deployment Timeline Summary

Key

COMPONENT	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Grid Modernization										
Advanced Metering Infrastructure (AMI)	■	■	■	■	■	■				
Customer Information Platform / Meter Data Management (CIP/MDM)	■	■	■	■	■	■				
Time-Varying Rates		■								
Peak-Time Rebate								■		
Prepay							■	■		
Stakeholder Engagement & Customer Education	■	■	■	■	■	■	■	■	■	■
Telecommunications	■	■	■	■	■	■	■	■	■	■
Self-Healing Grid	■	■	■	■	■	■	■	■	■	■
Hosting Capacity	■									
Distributed Energy Resources Management System (DERMS)				■	■	■	■	■	■	
Advanced Analytics		■	■	■	■	■	■	■	■	■
Voltage Optimization	■	■	■	■	■	■	■			
Locks Campus Microgrid		■								
Enterprise Asset Management System (EAMS)		■	■	■						
Outage Management System (OMS)					■	■	■			
Mainfeeder Hardening	■	■	■	■	■	■	■	■	■	■
Targeted Corridor Improvement	■	■	■	■	■	■	■			
Proactive Component Upgrades		■	■	■	■	■	■	■	■	■
Voltage Island Mitigation		■	■	■	■	■	■	■	■	■
Cyber Security	■	■	■	■	■	■	■	■	■	■
Physical Security	■	■	■	■	■	■	■	■	■	■
Transportation Electrification		■	■	■	■	■		■		

AMI OBSOLESCENCE PERSPECTIVE

By: Danny Freeman, July 2019

As technology continues to evolve and Utilities are increasingly inclined to modernize their operations, it is important to understand the impact of today's technology decisions. Utility executives and regulators must continue to challenge their decision-making processes by understanding the risk of selecting the wrong technologies and/or those that will soon become obsolete. This mindset must also be balanced by the damage that can be done by not investing in needed, value-adding technologies that drive innovation and benefit realization for fear of what may be coming in the future that might be better.

While this balance of risk and reward can be complex and very difficult in some areas of emerging and cutting-edge technologies, one conclusion can be safely drawn by utility executives, regulators, and distribution grid operators alike: Advanced Metering Infrastructure (AMI) or "smart meters" are here to stay.

Though technically AMI and smart meter technology has been in place for many years, there are several factors that clearly demonstrate that premature obsolescence of this technology is not a concern, nor will it be in the near-term. These include:

- The state of AMI technology and deployment today
- Vendor technology trends, investment decisions, and market developments
- Feedback from third parties and industry re-searchers

With over 60% of the electric meters in the United States now being smart meters, and several new and planned projects for large smart meter deployment in various stages, the industry has established AMI as the preferred and standard metering technology.

Importantly, it is also clear that vendors and solution providers are doubling-down on their investments in AMI-centric products and offerings and continue to support these solutions for new and past deployments. In fact, most meter manufacturers have eliminated or significantly de-emphasized the large-scale production of the old, analog meter types that require walk-up and drive-by reads because of the limited demand and relevance of them in todays modernized electric utility environment. The industry has moved forward, and the main, foundational vehicle for that modernized future is AMI technology.

Detractors or skeptics of this conclusion and the long-term viability of AMI may point to Automated Meter Reading (AMR) technology as a reference point for a similar metering solution that was touted as the "next big thing" for utilities. It is true that AMR technology represented a significant change and upgrade in metering and operational capabilities. However it is important to recognize that while the AMR solution was impactful, value-adding, and cost-beneficial when compared to traditional metering ("walk-up" meters requiring individual manual reads), there were several factors indicating that the AMR technology was to become replaced in the near-term.

Researchers and meter manufacturers had already begun development and conceptualization of testing of AMI solutions as early as the 1980s. As cellular and other two-way technologies became more prevalent through the 1990's and 2000's, meter manufacturers and utility technology providers began investing in research and development of how broad deployment of two-way communicating networks could be applied to metering, and the value it would unlock across multiple benefit streams. This was happening while AMR solutions were being actively deployed. This is not to say that the decision to invest in and deploy AMR technology during this timeframe was poor or misguided. On the contrary, those investments have proven to deliver operational benefits and cost reductions that have placed a downward pressure on customer rates. In many cases, utilities that invested in AMR did so with "eyes wide open", knowing that a potentially superior solution was under development and would very likely be fully tested, viable, and widely deployed once the next metering decision cycle was upon them.

Another telling sign that AMR technology had the potential to be more of an interim operational solution is that it was not fundamentally transformational by nature. While the value of AMR is clear and the benefits (largely meter reading cost reductions) have exceeded the costs to deploy, it did not fundamentally change how a utility operated the grid nor how they interacted with customers. AMR metering still required manual reading, it was simply done more efficiently via a drive-by van rather than a meter reader walking up to each home. While this was a benefit, other operational improvements were not addressed by this technology, including the costs associated with manually cutting and restoring power and gathering and assessing meter and system health information for trouble shooting and other operational work order types. AMR meters did not improve a utility's ability to effectively identify or respond to power outages, nor did they assist in the identification of meter tampering and theft that led to safety concerns and additional costs socialized to all customers.

The technology did not enable two-way communication, and thus did not further enable broad deployment of customer programs, rates, or dynamic options that rely on metering when compared to what traditional meters could provide. The further enablement of distributed energy resources integration is also not enhanced with AMR. These factors and others also led to the fact that while AMR meters did represent a sizable component of the meter population in the United States, they were not adopted at the levels we see AMI adoption today and anywhere near what is projected moving forward. Nearly all major utilities operating on AMR technology have already transitioned to AMI or are in the process of doing so.

AMI technology, on the other hand, truly does change the game for utilities and their customers. From an operational perspective, by leveraging remote, two-way communication, AMI further reduced and essentially eliminated meter reading costs, while also enabling remote execution of work orders, most notably remote connect and disconnect which is a significant cost for utilities. Other work order types are also significantly reduced or eliminated due to the ability to remotely interrogate and assess operational conditions without the need to send a utility employee to that location.

Outage management capabilities of AMI are also significant and have been proven across the country. The ability to integrate AMI with Outage Management Systems enables utilities to significantly improve their outage response efforts while driving an improved customer experience through proactive outage identification (customers no longer need to call in to report outages) and restoration, and the delivery of updates to customers on the estimated restoration time and related information.

The customer experience is also dramatically improved during non-outage conditions as a result of AMI. By capturing interval energy usage data and enabling two-way capabilities such as pricing signals and demand response functionality, customers with AMI meters are empowered to take direct control of their usage, and participate in programs, rates, and communication channels that were not possible before. Real-time, two-way communication of interval usage data and other data points, when combined with advanced analytics solutions also allow utilities to identify a wide range of operating conditions, such as meter tampering and theft. This positions the utility to take swift action for resolution, significantly reducing related safety concerns and socialized costs to customers.

In summary, AMR technology made sense at the time, but its fundamental characteristics and other market activities demonstrated that it was likely a bridge to a more advanced solution rather than the new standard. That solution is AMI.

From strictly a meter perspective, the asset performance to date has been quite strong. Manufacturers commit to a useful life of 15 years with an estimated 95% of meters expected to be fully functional and in service after that period. Importantly, AMI meters are also fully programmable to ensure compatibility both backwards and forwards, as communications technology continues to adapt and change in the future. This means that as enhancements are made to other components of the technology landscape, remote programming and updating of meters can be done "over the air", thereby avoiding costly field visits and eliminating the need for meter replacement that would have been required with the prior generation of hardware. This includes important updates related to security controls and configurations.

From a telecommunication backhaul perspective, leading AMI vendors have committed to operating the LTE (4g mobile communications standard) network for the foreseeable future and are committed to aligning with new and evolving standards and requirements, while collaboratively developing specific and actionable plans for technology upgrades. These technology components prolong the useful life in ways that were simply not possible before, positioning utilities to operate a long-term, flexible, and dependable solution.

A wide range of research and analysis has been performed by industry third parties and other organizations to look into the risk of obsolescence for AMI technology. The consensus of these organizations, including the Electric Power Research Institute ("EPRI")[1], the National Institute of Standards and Technologies ("NIST")[2], and the North American Electrical Manufacturers Association ("NEMA") is that while the continued evolution of technology is difficult to predict, the risk of obsolescence of AMI is very low and can be effectively managed by specific processes, practices, and partnership with vendors and solution providers that are already in place.

EPRI has clearly laid out their guidelines for how utilities can ensure that their system is future-proofed, such as closely monitoring and measuring the performance of the network to ensure remote upgrades and updates and able to be executed. Additionally, they recommend that a reserve of system memory and performance capability be set aside for future changes and updates. EPRI also notes that the AMI software architecture should also be flexible enough to support multiple communications protocols to not limit its use with a particular technology, and to allow for additional types and quantities of data to be transported to and correctly interpreted with the system. Lastly, they note that AMI systems are secure and agile without needing to rely on frequent and broad hardware implementations, while still meeting the requirements and performance expectations. NEMA has communicated a set of requirements for smart meter upgradeability that inform how utilities can ensure that their solution is flexible and 'future-proofed' to align with ongoing innovation and improvement throughout the AMI value chain.

While the future of AMI as the standard appears certain, it is important that utilities keep close tabs on market trends and vendor activities. If the last decade of transformation in the utility landscape has taught us anything, it is that technology is changing very quickly and can be quite disruptive and impactful. That being said, at this point, unlike the position of AMR technology, there is an absence of any known or proven deployment of a new metering method or technology beyond AMI of any consequence. The transformative nature of the benefits of AMI, both qualitative and quantitative are simply too compelling to ignore. The technology is here to stay, and its foundational role in the context of broader grid modernization should not be ignored in lieu of an as yet identified, deployed, or validated future metering technology.

REFERENCES

1. https://www.epri.com/#/pages/product/3002006738/?lang=en-US
2. https://www.nist.gov/programs-projects/advanced-metering-smart-distribution-grids